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November 19, 2014

***Via Electronic and Priority Mail***

Public Utility Commission of Oregon
Attn: Filing Center
P.O. Box 2148
Salem, OR 97308-2148
puc.filingcenter@state.or.us

**Re: OPUC Docket No. UM 1610**

Attention Filing Center:

Enclosed for filing in the above-captioned docket are an original and five copies of the *Response Testimony and Exhibits of Bill Eddie on behalf of OneEnergy, Inc.*

An extra copy of this letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann

Ken Kaufmann
Attorney for OneEnergy, Inc.

cc: UM 1610 Service List

Enclosures

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that, on the 19th day of November 2014, I have caused to be served the foregoing *Response Testimony and Exhibits of Bill Eddie on behalf of OneEnergy, Inc.* in OPUC Docket No. UM 1610 to those parties listed on the service list attached hereto, all of whom have waived their right to service by mail agreed to accept service by electronic mail at the address provided, below.

DATED this 19th day of November 2014.

LOVINGER KAUFMANN LLP

Jeffrey S. Lovinger, OSB 962147
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# BEFORE THE PUBLIC UTILITY COMMISSION

# OF THE STATE OF OREGON

## RESPONSE TESTIMONY OF BILL EDDIE

ON BEHALF OF

ONEENERGY, INC.

NOVEMBER 19, 2014

## INTRODUCTION

**Q. PLEASE STATE YOUR NAME, AND CURRENT EMPLOYMENT POSITION OR TITLE.**

A. My name is Bill Eddie. I am the President of OneEnergy, Inc., a developer of utility scale solar photovoltaic projects.

**Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS DOCKET?**

A. Yes, I provided testimony in Phase 1 of this docket. That prior testimony included my background and qualifications.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to respond to opening testimony filed by other parties on the appropriate solar capacity payment that should be made to standard renewable solar qualified facilities. Via comments to the Commission dated November 4, 2014, I noted our concurrence with the testimony of David Brown submitted on behalf of Obsidian Renewables, LLC ("Obsidian") on this issue.

**Q. HAS YOUR POSITION CHANGED AFTER REVIEWING OTHER PARTIES' TESTIMONY?**

A. No. In addition to Mr. Brown's testimony, both Staff witness Brittany Andrus and Oregon Department of Energy ("ODOE") witness Kacia Brockman are aligned on this issue. In Order No. 14-058, the Commission made a policy determination to pay different QF resources for their actual estimated capacity value. The adjustment sought by Staff, ODOE, Obsidian, and OneEnergy simply will make implementation of that policy more fair and accurate.

**Q. THE TESTIMONY OF GREG DUVALL ON BEHALF OF PACIFICORP ARGUES IT WOULD BE "SENSELESS" TO PAY A SOLAR PROJECT 39.5% OF THE CCCT CAPACITY COSTS (PAC/600, Duvall/7). DO YOU AGREE?**

**A.** I disagree with Mr. Duvall. Numerous utilities now assume that solar's dependable capacity contribution is in the range of 30% to 45%. In fact, in preparing its 2015 Integrated Resource Plan, PacifiCorp itself is now assuming solar's capacity value in Oregon is 36.7% for single-axis tracking systems, or 32.2% for fixed systems. Obsidian/202, Brown/5. These figures are nearly three times the capacity value for solar assumed in the 2013 IRP of 13.6%.

Other summer-peaking jurisdictions likewise recognize solar's capacity value in the 30% to 45% range. Idaho Power's solar capacity contribution is 32%. Idaho Power/600 Youngblood/13. Arizona Public Service reports that solar's capacity value is 45.9% at a penetration level of 242 MW and 30.5% at 758 MW penetration (APS's system peak is about 7,100 MW). Exhibit OneEnergy/301 (excerpt of 2013 Updated Solar PV Value Report by SAIC for APS[1]). In the Mid-Atlantic, the PJM Independent System Operator holds regular capacity auctions for generation resources as well as demand response (this capacity market is called the "Reliability Pricing Model"). PJM accords solar resources an initial capacity value of 38% of the generator's AC nameplate size. *See* Exhibit OneEnergy/302 ("PJM's Support of Variable Resources").

**Q. SHOULD THE COMMISSION DIRECT PACIFICORP TO BEGIN USING PACIFICORP'S CURRENT SOLAR CAPACITY CONTRIBUTION VALUE ASSUMPTION OF 36.7%?**

**A.** Yes, there is good cause to start using it now. PacifiCorp itself is using the same analysis in QF pricing proceedings in Wyoming. As with the Oregon method, PacifiCorp's Wyoming avoided cost rates equal the fixed and variable costs of the proxy CCCT during the deficiency period. Exhibit OneEnergy/303, Eddie/6 (Rocky Mountain Power Direct Test. G. Duvall at 5, lines 18-19, Wyoming PSC Docket No. 20000-458-EA-14

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[1] Full 2013 Updated Solar PV Value Report available at https://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf.

(November 7, 2014)) ("During the deficiency period avoided costs are equal to the fixed and variable costs of a proxy resource, currently a combined cycle combustion turbine ('CCCT')."). PacifiCorp's recent filing in Wyoming proposes to adjust the fixed costs of the deferred proxy CCCT by multiplying it by the capacity contribution of the resource type. OneEnergy/303, Eddie/10-11. The peak capacity contribution of tracking solar PV, as calculated by PacifiCorp, is 36.7% in the west and 39.1% in the east. OneEnergy/303, Eddie/11. PacifiCorp proposes to the Wyoming Public Service Commission to use the east value (39.1%). *Id*. The corollary for Oregon is the west value (36.7%).

**Q. STAFF'S OPENING TESTIMONY ON THIS ISSUE PRESENTED TWO OPTIONS FOR IMPLEMENTATION OF A CAPACITY ADJUSTMENT. DO YOU RECOMMEND EITHER APPROACH?**

A. Yes. I recommend Option 1 identified by Staff, in which the capacity contribution adjustment would be reflected in the price paid to solar QFs for all NERC on-peak hours. It is the simplest approach, and it is reasonably accurate. I am concerned Option 2 (i.e., paying the capacity adjustment only during months of maximum expected need) may inject additional complexity, and also require the Commission to speculate about the months in which peak system events will occur in the future. Over the 20-year term of a QF power purchase agreement, we may see shifts in the timing of peak events.

**Q. DO YOU AGREE WITH ODOE WITNESS KACIA BROCKMAN THAT A SIMILAR "DOUBLE DISCOUNTING" OCCURS UNDER THE STANDARD AVOIDED COST RATES (ODOE/600, Brockman/5)?**

**A.** Yes, a double discount, similar to the double discount in the Renewable Avoided Cost Prices, occurs in Standard Avoided Cost Prices. As it applies to Standard Avoided Cost Prices, this issue should be addressed in Phase II of this docket.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?**

**A.** Yes.

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF THE STATE OF OREGON

## EXHIBIT ACCOMPANYING RESPONSE TESTIMONY OF BILL EDDIE

ON BEHALF OF

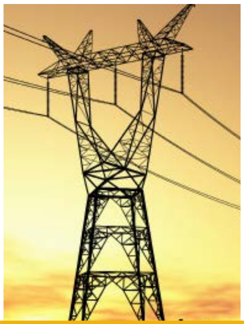
ONEENERGY, INC.

## Excerpts from *2013 Updated Solar PV Value Report* by SAIC for Arizona Public Service

Full Report available at https://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf

PREPARED FOR: ARIZONA PUBLIC SERVICE

# 2013 Updated Solar PV Value Report



MAY 2013

SAIC®

# Section 1
# INTRODUCTION

In January 2009, Arizona Public Service Company (APS) commissioned a landmark study (formally titled the *Distributed Renewable Energy Operating Impacts and Valuation Study* and referred to herein as the 2009 Study) that developed sound methodologies and processes for determining the value of distributed solar energy to the utility. Prepared by a group of technical experts led by R. W. Beck, Inc. in collaboration with APS management and staff, the 2009 Study was guided by input obtained through a deliberative stakeholder engagement process. The 2009 Study began in 2008 and reviewed, analyzed, and vetted both conventional and non-conventional approaches to valuing selected distributed solar technologies within the APS service territory.

The 2009 Study assessed specific value components of the three primary functional areas of APS: distribution, transmission, and generation. The 2009 Study, an exhaustive examination unique to APS, was among the first in the industry to provide a detailed assessment of how selected distributed solar generation resources could impact specific functions of utility operations and can be valued by a utility.

Changes in power markets conditions and an increase in distributed solar installations at APS since the 2009 Study prompted APS to retain SAIC Energy, Environment and Infrastructure, LLC (SAIC) - the acquiring entity of R. W. Beck, Inc. - to prepare an update (referred to herein as the 2013 Updated Solar PV Value Report, or Report). This Report revises prior assumptions and analyses concerning the valuation of distributed solar resources resulting in updated valuation estimates for APS. Specifically, this Report provides an update of the valuation of future distributed solar photovoltaic (solar PV) systems on the APS service territory installed after 2012.

Distributed solar systems are typically small-scale solar based technologies installed at or near retail load (i.e., located on or near a customer's house or business). Utility scale solar projects are generally larger in size, designed to sell solar generated power at the wholesale level, and interconnect direct to the utility side of the meter at the transmission level. Utility scale solar projects were not included in the 2009 Study and are not considered in this Report.

The 2009 Study assessed the value of both fixed and single-axis tracking solar PV as well as the value of residential solar hot water systems and commercial day lighting applications (referred to collectively as solar distributed energy). The predominant solar distributed generation anticipated in the next few years is fixed solar PV; therefore, this Report is based on the potential value from fixed solar PV systems. It should be noted however, the energy production projections and associated energy offsets outlined herein for solar PV could be comprised of a blend of distributed solar energy technologies.

The 2009 Study utilized a marginal or incremental approach for valuation. The methods and analyses developed included a review of the potential impacts from future solar resources on the APS system for specific target years. Unless otherwise noted herein, the methods and processes developed for the 2009 Study, including the incremental approach, have been applied to the calculation of the solar PV value described in this Report.

## 2009 Study Findings

The 2009 Study developed a range of potential unitized savings associated with solar distributed resources derived from a detailed analytical review of APS's unique systems. Assumptions impacting this range included: the configuration of the existing and future state of the APS system; the quantities and types of installed solar distributed energy capacity; future utility scale generation investments; estimated demand (load) requirements; projections of costs and resources to provide power to APS customers; and the associated needs for capital improvements to APS's distribution, transmission, and generation systems.

The resulting benefits of solar resources outlined in the 2009 Study were presented as a range of quantitative values, expressed in both then-current dollars and future dollars for the selected years of review (2010, 2015, and 2025). This range of values was based on the potential installed capacity of solar resources, associated generation characteristics, and associated reductions to the energy and capacity needs of APS. Generation characteristic ranges were developed using bookends of hypothetical deployment scenarios capturing the high, low, and targeted scenarios.

As shown in Table 1-1, the 2009 Study presented a stacked range (maximum and minimum) of potential unit savings (in cents per kilowatt-hour (kWh)) for 2025 by value category from low, distribution capacity related savings to high, energy related savings. Although not reflective of any specific scenario analyzed for the 2009 Study, these results identify the relative potential for savings by value categories.

The 2013 Expected Penetration Case results are presented in Table 1-1 for comparison purposes and are further discussed throughout this Report and summarized in Section 3.

**Table 1-1**
**2025 Solar PV Potential Value Range**

| Value Category | 2009 Study Potential Value (cents/kWh) (1) | 2013 Report Potential Value (cents/kWh) (2) |
|---|---|---|
| Distribution System | 0 to 0.31 | 0 |
| Transmission System | 0 to 0.51 | 0.32 |
| Generation System | 0 to 1.85 | 1.66 |
| Fixed O&M | 0.81 to 3.22 | 0.29 |
| Fuel, Purchased Power, Emissions & Gas Trans. | 7.10 to 8.22 | 5.93 |
| **Total** | **7.91 to 14.11** | **8.19** |

(1) Ranges represented in 2009 Study are not reflective of a single scenario.
(2) Values from the Expected Penetration Case, see text. Numbers are rounded and may not add.

## Summary of Updated Assumptions

APS system characteristics and market conditions have changed since the 2009 Study directly impacting the value associated with distributed solar PV based on Report assumptions including:

- The existing and projected costs for APS to produce and/or purchase power from the market have lowered dramatically since the 2009 Study, primarily as a result of lower natural gas prices used as a fuel source for electric generation. In 2008, natural gas prices were approximately $9.00 per million British Thermal Units (MMBtu); in 2012 natural gas prices were approximately $3.50 per MMBtu. Downward pressure on natural gas prices are the result of increased national supply due to: exploration; production, including widespread use of hydraulic fracturing; and improvements in natural gas recovery methods and technologies.
- Projections for carbon dioxide ($CO_2$) emission related costs have reduced significantly since the 2009 Study. In the 2009 Study, estimates for future $CO_2$ costs were approximately $50 per ton (in 2025), based on the consideration of future federal legislation under consideration at that time. The $CO_2$ reduction legislation was never passed, nor does it appear that such legislation will be introduced in the near future. However, APS has incorporated $CO_2$ emission related costs in its planning documents based on an analysis conducted by Charles River Associates, whereby costs are incurred beginning in 2019 and are assumed to escalate to a value of approximately $22.00 per ton in 2025.
- The number of installed distributed solar PV systems on the APS system has increased dramatically. In 2008, APS had under 1,000 solar PV systems installed in its service territory. As of 2012, this number had increased to over 14,000. According to APS, over 80 percent of the new solar PV systems in 2012 were installed under third-party solar leases. Third-party lease and financing options have driven higher market participation within APS's service

territory than anticipated in the 2009 Study. Additionally, approximately 60 percent of customers with solar PV systems have opted into one of APS's time of use (TOU) retail rate tariffs. The projected values from solar PV developed in this Report reflect the incremental solar PV installations from the end of 2012 to the target years identified herein. This data was used as a baseline for this Report.

- APS reports that only a very small percentage of the solar PV systems installed in its service territory utilize single-axis tracking technologies. As a result, this Report focuses on the value of fixed solar PV as the expected incremental system to be installed in the future. In general, single-axis tracking technology could be expected to have slightly higher energy related value as a result of modestly higher hourly energy production, as well as slightly higher capacity related value, as a result of daily production that extends further into the evening hours, relative to fixed solar PV systems. The scenario analysis developed for this Report, as described herein, could reasonably be considered to include output from the relatively small number of existing and expected single-axis tracking systems installed in the APS service territory.
- APS's solar PV incentive programs, as approved by the Arizona Corporation Commission (ACC), have allowed the organic market growth for solar PV deployment to meet the requirements for solar generation on the system as a whole. An analysis of the locations of solar PV installations under this "market-based" approach have not resulted in significant localized penetration regions, but instead these installations have been geographically spread-out across the APS service territory. This Report assumes future deployment locations consistent with the observations of existing penetrations to date.
- Total load (demand and energy use) projections for APS customers are markedly lower than the forecasts utilized in the 2009 Study due to the economic recession and general economic slowdown across the country as well as the state of Arizona energy efficiency standards that have reduced both energy and demand projections. As a result, the projected need for capital improvement projects on the APS system in general has decreased.
- The 2009 Study considered the value of marginal avoided losses by comparing projected annual hourly system load profiles with and without solar resources to determine both annual energy and peak demand losses at the system level for each deployment scenario. However, this approach was theoretical in nature and it has not been technically feasible to verify the accuracy of the estimate based on marginal losses. Accordingly, this Report utilizes known system average energy and demand losses observed and measured by APS in its approach to value the avoided losses as a result of the increased solar PV projections.

The impact of these key assumption changes and their incorporation into the value calculations for solar PV generation are discussed herein.

## Summary of Methodology

Unless otherwise noted, and to the extent possible, the 2013 Updated Solar PV Value Report utilizes the 2009 Study methodology for assigning incremental value to future solar PV deployments throughout the APS service territory. Description of these methodologies is detailed in Section 2 of this Report. These methodologies were applied to the following three functional areas of the utility, which are also referred to as value categories for this Report:

- Distribution;
- Transmission; and
- Generation (Energy and Capacity).

This Report provides an estimate of the incremental value of future solar PV for the APS system for 2015, 2020, and 2025, which are the target years identified for the analysis conducted herein. Values are stated in current-year dollars (2013) for these periods, as well as in nominal dollars. The hypothetical bookends developed for the 2009 Study were theoretical scenarios that were meant to explore the opportunity for value associated with a range of various types and configurations (including location) of distributed solar systems. This Report focuses on realistic expectations for growth of solar PV in the APS service territory based on the penetration to date of specific applications of solar PV systems and updates the value categories identified in the 2009 Study.

## Other Sources of Information

Since the 2009 Study, APS has investigated the costs and performance characteristics of solar PV installed on its system. Sources developed or reviewed by APS include:

- the 2012 Integrated Resource Plan (2012 IRP), dated April 2012;
- the APS 2013-2022 Ten-Year Transmission System Plan (Ten-Year Plan); and
- the *"Solar Photovoltaic (PV) Integration Cost Study"*, prepared by Black and Veatch, dated November 2012, on behalf of APS, that reviewed the costs associated with integrating significant numbers of solar PV systems on a year-round basis on the APS system.

The 2009 Study did not include a valuation of solar PV integration costs because little information regarding these costs was available at that time, therefore this Report does not include a value for potential integration costs that APS will likely incur. The "*Solar Photovoltaic (PV) Integration Cost Study"* represents the most current review available for potential integration costs APS could expect as solar PV deployment increases over time.

SAIC relied upon information provided by APS as well as information concluded in these supplemental reports for this Report. SAIC reviewed all the data provided by APS for this Report for reasonableness.

(1) Projections are incremental to the installed solar PV on the system as of the end of 2012. Projections include 7 percent losses, see text and Table 2-3.
(2) Megawatt-hour (MWh)

### 2012 Installed and 2013 Projected Solar PV Capacity

By the end of 2012, APS had approximately 222 megawatts AC ($MW_{AC}$) of total nameplate installed distributed solar PV on its system, inclusive of both residential and commercial applications[1]. In 2013, APS anticipates a significant increase in projected installations which would result in approximately 296 $MW_{AC}$ of cumulative installed nameplate distributed solar PV.

The large increase in predictions for 2013 is due to concrete distributed energy programmatic activity by APS retail customers. Beginning in 2013, APS had existing solar PV reservations and incentive funding which could provide over 50 MW of residential capacity and over 50 MW of commercial capacity.

The solar PV capacity projections identified above are nameplate solar PV capacities and are not dependable capacity values. Dependable capacity values are discussed later in this Report.

## Dependable Capacity

A critical aspect of the 2009 Study was the determination of the dependable capacity available from solar PV, which is the ability of solar PV to reliably serve APS's total system load during peak periods. The dependable capacity analysis was used to determine the amount of solar PV capacity required to provide the same level of reliability as traditional generation resources. This Report utilizes the methodology for calculating the dependable capacity that was developed for the 2009 Study. Dependable capacity calculations were developed separately for the generation, transmission and distribution systems.

This Report (and the 2009 Study) determines capacity value from solar PV installations by their relative contribution to peak load. For generation and transmission systems, the peak load is determined at the system level (system peak) because the installed generation and major transmission lines must be designed to serve the system load requirements at that time. The system peak is the one hour of the year for which the customers' load is the highest. In addition, the generation analysis includes changes to Effective Load Carrying Capacity (ELCC), which includes loss of load simulations, which are a measure of reliability used to calculate dependable capacity values for generation.

The distribution and sub-transmission systems are designed to meet the localized needs of particular feeders or substations. This feeder peak may or may not be coincident with the system peak; and is driven by the usage of the customers that are served by those feeders. If the load is primarily residential, the peak is expected to be rather late in the day, when customers return home and begin to increase their

[1] This value reflects a preliminary projection of 2012 year end installed distributed solar PV capacity.

electricity usage. Alternatively, if the load is primarily commercial, the peak may be earlier in the day, when customers are at work.

Solar PV systems also have their own peak; the hour in which they generate the maximum amount of electricity. Assuming flat panel type of solar PV systems, as identified in this Report, the production peak is generally at 1:00 p.m., when the sun is at its highest point and is producing the most irradiance. Production decreases rapidly throughout the afternoon until it is totally diminished in the evening. It is the relationship between the production of the solar PV systems at the time of the load peak of either the system (for generation and transmission) or the feeder peaks (for distribution and sub-transmission) that results in the calculation of dependable capacity.

### Dependable Capacity – Generation / Transmission

Deferring generation and transmission investment affects the planning, design, and operation of the transmission system which is highly regulated by North American Reliability Corporation (NERC) Reliability Standards. The reliability criteria are deterministic and are based on allowable system performance following contingencies. For the grid-level transmission system (i.e. higher than 69-kilovolt (kV)), specific projects that are related to planned generation resources that could potentially be postponed or eliminated with the future solar PV penetration scenarios were evaluated with those specific generation resources.

Therefore, the methodology for determining the ability to defer generation and related transmission investments requires determining the dependable capacity of the solar distributed generation and thus the dependable load reduction and the resulting impact on reliability. The 2009 Study used an industry-accepted methodology to measure the reliability of meeting the APS system load with a given portfolio of resources. The approach was based on a statistical analyses to determine the level of solar output that would be sufficient to allow a generation deferral without impacting system reliability.

To evaluate the dependable capacity of solar resources, APS performed a series ELCC simulations, which is a measure of reliability used to calculate dependable capacity values for generation. The ELCC simulations modeled the APS existing portfolio after adding 100 $MW_{AC}$ of solar PV nameplate capacity to determine its dependable capacity, as described in the 2009 Study. Because the ELCC measurement can vary significantly depending on the underlying load shape, the ELCC computations were performed for five historical annual hourly load profiles: 2003 through 2007.

For this Report, the solar PV dependable capacity was calculated using the same ELCC results used in the 2009 Study. Table 2-2 outlines the solar PV capacity value percentages used to arrive at the associated dependable capacity projections for 2015, 2020, and 2025.

**Table 2-2**
**Solar PV Dependable Capacity – Generation**

| Scenario | 2015 | 2020 | 2025 |
|---|---|---|---|
| **Expected Penetration Case** | | | |
| Nameplate PV Capacity ($MW_{AC}$) w/ losses | 242 | 768 | 1,504 |
| Avg. PV Capacity Value | 45.9% | 30.5% | 21.0% |
| Incremental Dependable Capacity (MW) | 111 | 235 | 316 |
| Incremental Capacity Value of the Next 50 MW | 34.1% | 11.4% | 5.3% |
| **High Penetration Scenario** | | | |
| Nameplate PV Capacity ($MW_{AC}$) w/ losses | 242 | 971 | 3,044 |
| Avg. PV Capacity Value | 45.9% | 26.4% | 12.4% |
| Incremental Dependable Capacity (MW) | 111 | 256 | 376 |
| Incremental Capacity Value of the Next 50 MW | 34.1% | 6.4% | 3.0% |
| **Low Penetration Scenario** | | | |
| Nameplate PV Capacity ($MW_{AC}$) w/ losses | 166 | 338 | 734 |
| Avg. PV Capacity Value | 48.4% | 43.7% | 33.3% |
| Incremental Dependable Capacity (MW) | 80 | 148 | 244 |
| Incremental Capacity Value of the Next 50 MW | 41.9% | 29.6% | 17.4% |

Note: Incremental Nameplate Solar PV Capacity includes 11.7 percent peak hour demand loss

It was determined in the 2009 Study that significant implementations of solar PV can result in a shift in the APS system peak to a later hour when solar PV resources are less productive. With no incremental solar PV, the APS system is projected to peak in the 17:00 hour. Because the output of the solar distributed resources becomes significantly less as the available sunlight diminishes at dusk, the delay of the peak hour to a later hour diminishes the ability of the solar distributed resources to meet the electric system peak demand and satisfy reliability planning criteria. Table 2-2 clearly indicates that as the peak shifts and solar resources become less productive, the incremental capacity values are reduced somewhat exponentially (as shown for each scenario under Incremental Capacity Value of the Next 50 MW).

### Dependable Capacity – Major Transmission Projects

As discussed in the 2009 Study, potential deferral of transmission investment is due to the reduction in effective load growth as a result of locating the solar PV at the load, delaying the time at which the system would reach its peak load. The 2009 Study concluded that solar resources were not projected to have a significant impact until the end of the then current ten-year transmission plan. Since specific project data was not available beyond that time, simplifying assumptions were utilized to determine what types of investments might be necessary on APS's transmission system beyond that period.

For this Report, the Ten-Year Plan includes proposed major transmission projects up to the end of the study period (2025) when significant solar penetration is anticipated in the Expected Penetration Case and High Penetration Scenario. Therefore, the potential for delaying specific transmission projects based on specific load levels has been analyzed by these solar PV penetration scenarios.

SAIC reviewed information provided by APS for forecasted capital investments to identify the major planned transmission projects corresponding to system growth needs that could potentially be deferred. For the target years, SAIC conducted a comparison of the APS projected hourly loads both with, and without, solar PV installed to estimate revised system peaks for the target years at expected and high penetration levels. The difference between the revised system peaks and the reference case peak loads without solar PV determined the dependable capacity for transmission deferrals. The revised peaks were compared to the proposed transmission project load levels to determine if the associated project costs and timing could be delayed past the target years of this Report.

### Dependable Capacity –Sub-Transmission and Distribution

For the 2009 Study, hourly normalized solar distributed energy data was also used to calculate dependable capacity at the time of the individual feeder peak loads for sample feeders on the distribution system[2]. An average cost of distribution improvements per MW of non-coincident load growth was used to calculate the value to the distribution system and was applied under a hypothetical scenario, assuming solar installations would be targeted in high concentrations along the required feeders or near substations.

As indicated previously, APS is experiencing an organic and non-selective market based growth of solar PV systems that has resulted in a geographically diverse (i.e. non-concentrated) penetration pattern that does not coincide with the 2009 Study targeted scenario. Based on the existing locations of existing solar PV systems within the APS service territory, an evaluation was conducted to determine if sufficient solar PV has been installed on existing distribution feeders to defer planned upgrades. This methodology was then applied to projected solar PV forecasts spread across all feeders to determine the number of feeders for which potential upgrades could be deferred due to the reduced peak load.

For the 69-kV sub-transmission system, APS identified specific load-growth based planned projects that could potentially be postponed by the future solar PV penetration scenarios. The projected solar PV penetration at the feeder level was totaled to

[2] In the 2009 Study the hourly energy data was obtained using SAM 2.0 developed by NREL, using TMY production data.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

EXHIBIT ACCOMPANYING RESPONSE TESTIMONY OF
BILL EDDIE

ON BEHALF OF

ONEENERGY, INC.

PJM's Support of Variable Resources (April 18, 2012)

# PJM Interconnection's market rules and Open-Access Transmission Tariff encourage the reliable and efficient integration of variable energy resources like solar and wind into the grid. PJM has taken a number of other measures as well to reduce barriers and facilitate the ability of variable resources to integrate into the system while ensuring continued reliability.

Recognizing the potential impact of a significant infusion of new renewable energy sources not only on PJM but on the Eastern Interconnection as a whole, PJM acted as a catalyst in bringing together the transmission planning authorities across the interconnection to discuss how to create an interconnectionwide planning framework.

The outcome was the formation in 2009 of the Eastern Interconnection Planning Collaborative (EIPC), which is using the existing regional transmission plans of these industry groups as the basis to conduct transmission analyses for the interconnection as a whole. These analyses will address the impact of large amounts of variable energy resources that are expected to come on line in the future.

The wide scope of PJM's operations and markets provides ample opportunities for variable energy resources to conduct business. The following PJM policies, protocols and programs are in place and provide needed support for the development of variable energy resources in the PJM region.

- In the Real-Time Energy Market, there are no penalties levied on generation for scheduling deviations. Instead, all generation can buy power at market prices to meet previously arranged schedules, as for example, if wind output drops. Wind generation also receives market-based revenues if wind project deliveries exceed scheduled amounts.
- Variable resources benefit from the short scheduling intervals of PJM's market. Generators of any type can self-schedule with 20-minutes notice; PJM typically approves a dispatch case and sends out new dispatch signals every four to five minutes. This helps reduce the need for regulation service to deal with changes in load within each hour.
- PJM established a centralized wind power forecasting service in 2009. Aggregated data from the service is made available to members and is used to help determine the next-day unit commitment to ensure there are sufficient reserves. The forecasting also was designed to encourage participation by wind resources in the Day-Ahead Energy Market.
- Variable resources have the ability to earn revenues by participating as capacity resources in PJM's capacity market, the Reliability Pricing Model (RPM). Because of the intermittent nature of these resources, PJM's capacity valuation procedure allows wind to receive capacity credit on a rolling three-year average of actual performance over the previous three summers. If they have been in operation for less than three years, wind and solar projects receive a class-average value – for wind, 13 percent of nameplate capability and for solar photovoltaic facilities, 38 percent of AC rating.

PJM is conducting two integration studies to examine the impact of renewable resources on the planning and operation of the transmission system.

One study is assessing the impact of large-scale renewable energy integration on operations, planning and markets. The other study is evaluating the impact of state renewable portfolio standards (RPS) on the planning of the high-voltage transmission system at the 345-kilovolt level and above. The study will show what the PJM system could look like in 2021 and 2026 in terms of the transmission enhancements needed to meet the RPS standards of the PJM states.

PJM has taken a number of other steps to help support the effective integration of variable energy resources. These include:

- Forming the Intermittent Resources Task Force (IRTF) to examine the operational, reliability and market issues specific to variable resources. The IRTF has been focusing its attention on three areas: assessing operational impacts, examining interconnection standards and reviewing interconnection study protocols for intermittent resources.

- Implementing changes in software to enhance the management of wind resources.

- Participating in a variety of forums and studies by the North American Electric Reliability Corp. and others dealing with the integration of variable energy resources.

4/18/2012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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

EXHIBIT ACCOMPANYING RESPONSE TESTIMONY OF
BILL EDDIE

ON BEHALF OF

ONEENERGY, INC.

Excerpt of Rocky Mountain Power Direct Test. G. Duvall, Wyoming PSC Docket No. 20000-458-EA-14 (November 7, 2014)

Docket No. 20000-___-EA-14
Witness: Gregory N. Duvall

BEFORE THE WYOMING PUBLIC SERVICE
COMMISSION

ROCKY MOUNTAIN POWER

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Direct Testimony of Gregory N. Duvall

November 2014

**Q. Please state your name, business address and present position with PacifiCorp dba Rocky Mountain Power ("the Company").**

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Director, Net Power Costs.

## QUALIFICATIONS

**Q. Briefly describe your education and professional experience.**

A. I received a degree in Mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by PacifiCorp in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon and was responsible for directing the analytical effort for the Multi-State Process ("MSP"). Currently, I direct the work of the load forecasting group, the net power cost group, and the renewable compliance area.

## PURPOSE OF TESTIMONY AND RECOMMENDATION

**Q. What is the purpose of your testimony?**

A. My testimony is provided in support of the Company's November 7, 2014 filing to update Schedule 37, Avoided Cost Purchases from Qualifying Facilities. The Company's filing provides updated Schedule 37 prices and proposes several changes to the way avoided costs are calculated for Schedule 37. My testimony provides support for each change proposed by the Company.

**Q. What QF resources qualify for Schedule 37 pricing?**

A. Published rates under Schedule 37 are available to QFs up to 1 MW capacity and with an annual capacity factor of 70 percent or lower, or to QF projects up to 10 MW and with a capacity factor higher than 70 percent.

**Q. Please describe the specific changes to the calculation of Schedule 37 rates as proposed by the Company.**

A. The Company proposes the following changes to the calculation of avoided cost rates in Schedule 37:

- Integration costs for wind and solar qualifying facilities ("QFs") should be included as a reduction to avoided costs consistent with the integrated resource plan ("IRP").
- Avoided capacity costs should be adjusted for the capacity contribution of intermittent QF resources consistent with the IRP.
- Determination of the resource deficiency period, and avoided capacity costs, should be based on the next deferrable resource identified in the Company's most recent IRP or IRP update.
- Avoided costs during the sufficiency period should not include capacity costs related to the deferral of a simple cycle combustion turbine ("SCCT") consistent with the IRP and pricing for large QFs under Schedule 38. Avoided costs should be offered on a volumetric basis (i.e. dollars-per-megawatt-hour, or $/MWh), replacing the rates paid as a fixed capacity payment plus a flat energy rate.

**Q. Was the Company required to update the Schedule 37 avoided cost rates irrespective of the proposed changes?**

A. Yes. The Company is required to file updated system data and avoided cost rates in order to be in compliance Section 317 of the Commission's Rules regarding arrangements between electric utilities and QFs within the meaning of Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Section 317 (e) of the Commission's Rules requires system data from which avoided costs may be derived to be filed not less often than every two years.

**Q. When were the rates currently in effect approved by the Commission?**

A. Wyoming Schedule 37 rates were last approved by the Commission November 19, 2012.

**Q. Why is the Company proposing changes to the way Schedule 37 is calculated?**

A. The proposed changes are required to achieve the PURPA objective of customer indifference to the Company's mandatory purchase obligation of QF output at avoided cost rates. The Company's proposed changes achieve this objective by reflecting avoided costs consistent with the Company's most recent resource planning information, accounting for the unique characteristics of intermittent QF resources, and eliminating unnecessary differences between the calculation of avoided costs for small QFs under Schedule 37 and large QFs under Schedule 38.

Without the proposed changes to the Schedule 37 methodology, retail customers will pay prices for QFs that are higher than the avoided cost of energy and capacity from other sources.

**Q. What is the impact of updating Schedule 37 avoided cost rates?**

A. Table 1 below shows the current Schedule 37 rates and the updated rates including the proposed changes in methodology.

**Table 1**

| 20 Year (2015 to 2034) Nominal Levelized Prices ($/MWh) | | | |
|---|---|---|---|
| | Current Rates (A) | Proposed Volumetric Rates (B) | Change (C) |
| Base Load (85% of CF) | $53.74 | $44.09 | ($9.65) |
| Wind (40% of CF) | $66.51 | $36.13 | ($30.38) |
| Fixed-Tilt Solar (18.5% of CF) | $94.54 | $42.75 | ($51.79) |
| Tracking Solar (29% of CF) | $75.66 | $43.16 | ($32.50) |

**Q. Are the proposed Schedule 37 rates in this filing in-line with rates in any other states served by the Company?**

A. Yes. On October 21, 2014, the Utah Public Service Commission approved updated Schedule 37 rates. The Company's proposed changes to Wyoming Schedule 37 are identical to changes recently approved in Utah Schedule 37 rates. Table 2 below shows that the proposed Wyoming Schedule 37 rates are comparable to those recently approved in Utah.

**Table 2**

| QF Resource Type | Proposed WY Schedule 37 Price ($/MWh) | Current UT Schedule 37 Price ($/MWh) |
|---|---|---|
| Base Load | $44.09 | $45.46 |
| Wind | $36.13 | $35.79 |
| Fixed-Tilt Solar | $42.75 | $43.77 |
| Tracking Solar | $43.16 | $45.81 |

**Q. How is the remainder of your testimony organized?**

A. I first provide background information regarding the current method approved by the Commission for calculating avoided cost rates under Schedule 37. Next, I discuss each of the proposed changes and provide support for each change.

## SCHEDULE 37 BACKGROUND

**Q. Please provide a brief history of Schedule 37 pricing in Wyoming.**

A. The framework for the calculation of rates under Schedule 37 was first approved by the Commission in Docket No. 20000-ET-92-45 and Docket No. 20000-ET-92-18. Schedule 37 prices have been reviewed and updated in several subsequent dockets, including most recently in Docket No. 20000-419-EA-12.

**Q. Please describe the currently-approved method for calculating avoided costs for small QFs qualifying for published rates under Schedule 37.**

A. The determination of avoided costs is divided into two periods: resource sufficiency and resource deficiency. During the sufficiency period, avoided energy costs are calculated using GRID, the Company's production cost model. Net power costs ("NPC") are calculated in GRID using two system dispatch simulations; one without any new QF resources and one with an additional 50 average megawatt ("aMW") resource included at zero cost. The difference in NPC between the two GRID runs divided by the energy produced by the 50 aMW QF resource determine the avoided energy cost. The current method also includes an additional capacity payment based on a three-month seasonal capacity purchase priced at the fixed cost of a SCCT. During the deficiency period avoided costs are equal to the fixed and variable costs of a proxy resource, currently a combined cycle combustion turbine ("CCCT").

**Q. Is this same method used to calculate avoided costs for large QFs under Schedule 38?**

A. No. Avoided costs for large QFs under Schedule 38 are calculated using the Partial Displacement Differential Revenue Requirement ("PDDRR") method. The methods are similar in that both utilize the GRID model to determine avoided costs during the sufficiency period and both include capacity costs of a CCCT in the deficiency period. The PDDRR method, however, continues to use a combination of the GRID model to determine energy costs and partial displacement of a CCCT to determine capacity costs during the deficiency period rather than basing avoided costs solely on the proxy CCCT capacity and energy costs. Furthermore, the PDDRR method accounts for the specific characteristics of a proposed QF, including geographic location and any transmission constraints, and prices are prepared for individual QF projects using project specific generation profiles rather than providing the same published prices for all QFs.

**Q. Will the changes proposed by the Company make Schedule 37 unnecessarily complicated?**

A. No. The changes proposed by the Company are discrete and easy to administer. Distinct rates will be published for base load, solar, and wind resources, and the mechanics of the avoided cost calculation for capacity and energy costs will largely remain intact. The benefits of transparency and ease of use afforded by Schedule 37 will not be diminished by the Company's proposals in this filing.

## PROPOSED CHANGES

### Integration Costs

**Q. What does the Company propose with regard to integration costs in Schedule 37?**

A. The Company proposes to publish distinct price streams for wind and solar resources that are reduced by the cost of integrating intermittent resources onto the Company system, consistent with the current method approved for large QFs. Tables 6A through 6D in Exhibit 3 of the Company's filing show how the adjustment for integration costs is made to the avoided cost rates.

**Q. How are integration costs calculated?**

A. The Company has prepared studies to calculate wind integration costs in the last several IRPs. The most recent study was completed in October 2014 and has been submitted to a technical review committee. A copy of the latest study is provided as Exhibit RMP___(GND-1). The 2014 wind integration study calculated integration costs for wind resources of $3.06/MWh in 2015 dollars.

Wind integration studies are performed to estimate the operating reserves required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation ("NERC") reliability standards. The Company must provide sufficient operating reserves to allow the Balancing Authority to meet NERC's control performance criteria at all times. These incremental operating reserves are necessary to maintain area control error within required parameters due to sources outside the direct control of system operators including intra-hour changes in load demand and wind generation. The study results in a volume of operating reserves and the associated cost of these operating reserves required to manage load and wind generation variation in PacifiCorp's Balancing Authority Areas. In the current Schedule 37 filing, the Company used the costs calculated in its 2014 integration study to adjust the avoided costs for wind QFs. In addition, the wind study determines the system balancing costs required to manage wind resources. System balancing costs capture the costs associated with the need to commit resources on a day-ahead basis, but operating those resources against actual conditions that occur the next day.

**Q. Has the Company also completed a solar integration study?**

A. No. The Company has not yet performed a solar integration study. As a result, solar integration costs in the current filing were assumed to be 25 percent of wind integration costs, which is consistent with the assumptions used in the Company's IRP. When a solar integration study is available, the Company will include it in future applications to update Schedule 37.

**Q. Has the Commission addressed how integration costs should be included in the calculation of avoided costs for intermittent resources?**

A. Yes. In its Order in Docket No. 20000-250-EA-06 (Record No. 10636) the Commission approved a Stipulation that required deduction of integration costs from the avoided costs when determining avoided costs prices for large QFs with intermittent generation.

**Q. Do current Schedule 37 rates include an adjustment for integration costs?**

A. No.

**Q. Are retail customers indifferent if integration costs are not included in the calculation of avoided costs?**

A. No. If an adjustment is not made to avoided costs to account for the cost to integrate intermittent resources, retail customers must bear the cost of integrating these resources into the Company's system, violating the ratepayer indifference objective prescribed by PURPA.

**Capacity Contribution**

**Q. What does the Company propose with regard to capacity contribution in Schedule 37?**

A. Capacity costs included in the calculation of Schedule 37 rates should be adjusted to reflect the capacity contribution of intermittent wind and solar resources. The capacity contribution of wind and solar resources, represented as a percentage of a resource's nameplate capacity, is a measure of the ability of these resources to reliably meet demand. For purposes of calculating Schedule 37 avoided cost prices, the capacity contribution of a QF resource must be applied to the fixed costs of the deferred proxy CCCT to accurately determine the capacity costs that can be avoided due to the addition of the QF resource.

**Q. How is the capacity contribution of wind and solar resources calculated?**

A. The Company recently completed a capacity contribution study in support of its 2015 IRP. The Company calculated peak capacity contribution values for wind and solar resources using the capacity factor approximation method ("CF Method") as outlined in a 2012 report produced by the National Renewable Energy Laboratory.[1] A description of the Company's study and the resulting capacity contributions for wind and solar resources are provided as Exhibit RMP___(GND-2). The results of the study show the following capacity contribution levels for wind, fixed-tilt solar, and tracking solar resources.

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report). http://www.nrel.gov/docs/fy12osti/54704.pdf

**Table 3**

| | Wind | | | Fixed Solar PV | | | Tracking Solar PV | | |
|---|---|---|---|---|---|---|---|---|---|
| | West | East | Weighted Average | West | East | Average | West | East | Average |
| Peak Capacity Contribution | 25.4% | 14.5% | 18.1% | 32.2% | 34.1% | 33.1% | 36.7% | 39.1% | 37.9% |

The Company proposes to adjust the amount of capacity costs included in avoided costs for wind and solar QFs by their respective capacity contributions. Tables 6A through 6D in Exhibit 3 of the Company's filing show how the adjustment for capacity contribution is made to the avoided cost rates.

**Q. What differentiates capacity contribution from capacity factor?**

A. The capacity factor of a generating resource is a measure of how much energy that resource is expected to produce over a given period of time. Like capacity contribution, the capacity factor is represented as a percentage of plant capacity; however, the two metrics have entirely different meanings. For example, consider two hypothetical power plants operating at a 50 percent capacity factor. Both plants produce energy at half of their full capability over the course of a year. However, assume one plant achieves a 50 percent capacity factor by producing energy in hours when the probability of reliability events are lowest and the other plant achieves its 50 percent capacity factor by producing energy in hours when the probability of reliability events are highest. The former would have a low capacity contribution value and the latter would have a high capacity contribution value. For Schedule 37 avoided cost rates, the QF's capacity contribution is applied to the capacity costs of the proxy CCCT, reducing the amount paid to an intermittent QF for capacity.

**Q. Do current Wyoming Schedule 37 rates recognize a reduced level of capacity payments for intermittent resources?**

A. No. Current rates paid to intermittent solar and wind QFs include deferral of a base load resource of the same nameplate capacity as the QF.

**Q. Are retail customers indifferent if the capacity contribution of intermittent solar and wind QFs is not reflected in the calculation of avoided costs?**

A. No. As described earlier, during the deficiency period Schedule 37 rates are calculated as the all-in cost of a base load CCCT. If no adjustment is made to reflect the capacity contribution of a QF, rates paid to intermittent solar and wind QFs would reflect deferral of a base load resource of the nameplate capacity as the QF even though an intermittent QF resource only provides a portion of the capacity provided by the CCCT. For example, during the deficiency period a 1 MW wind or solar QF is currently assumed to displace 1 MW of the proxy CCCT. Without an adjustment for capacity contribution, payments to intermittent QFs would not accurately reflect the Company's avoided costs.

**Capacity Costs and Resource Sufficiency/Deficiency**

**Q. What does the Company propose with regard to avoided capacity costs?**

A. Avoided capacity costs based on an avoided thermal resource should only be included during the deficiency period, which should be marked by the next deferrable resource included in the Company's IRP or IRP update. The current method of including the capacity costs of a SCCT during the sufficiency period should be eliminated from the calculation of Schedule 37 avoided costs. This change conforms Schedule 37 rates to the Company's resource planning process and is consistent with the avoided cost calculation for large QFs under Schedule 38.

**Q. Are the Company's resource procurement plans an important consideration in the determination of Schedule 37 rates?**

A. Yes. The current method for calculating Schedule 37 rates during the deficiency period relies on the fixed and variable costs of the next deferrable resource in the Company's latest IRP or IRP Update. Table 1 of the Company's Schedule 37 filing shows that in the 2013 IRP Update a 423 MW CCCT scheduled to come online in 2027 is the Company's next deferrable thermal capacity resource; consequently 2027 should mark the start of the resource deficiency period and the inclusion of deferred capacity costs in avoided cost rates. Prior to the start of the deficiency period in 2027, the Company will not procure additional thermal capacity resources but will utilize front office transactions, or wholesale market purchases, to meet its needs. These facts are taken into account when the Company evaluates significant resource acquisitions, including environmental upgrades and other requests for proposals, and the valuation of capacity and energy provided by a QF should not be treated differently.

**Q. What capacity costs are currently included in Schedule 37 rates during the sufficiency period?**

A. Current Schedule 37 rates include capacity payments based on three months of the annual capacity cost of a SCCT during the sufficiency period. Avoided cost prices during this period must be changed to be consistent with the Company's resource procurement plans and should not include an assumption that a QF will avoid the cost of a SCCT during part of the year. Prior to the addition of the next thermal resource in the Company's IRP, resource needs will be met using wholesale market transactions. Including extra capacity costs in the sufficiency period burdens retail customers with QF costs that are higher than the costs actually avoided by the Company.

In the past, the period of resource deficiency has been determined using a simulated load and resource balance calculated in the GRID model. The deficiency period was assumed to begin when the GRID model was short both energy and capacity on an annual basis. However, while the GRID model is a useful tool for determining system costs for a given set of resources, it provides only one snapshot of the Company's system dispatch under a given set of assumptions and it is not the model used to determine the Company's long-term resource plans. Through the IRP process the Company models its projected resource needs on a least-cost, least-risk basis and determines the timing and type of the resources it plans to procure in the future. Marking the period of resource deficiency based on capacity and energy shortages in a GRID model run is unnecessary and could result in inconsistencies with the Company's actual resource procurement plans as determined by the IRP.

**Q. Is the proposed change to Schedule 37 for avoided capacity consistent with the calculation of avoided costs for large QFs?**

A. Yes. Under the PDDRR method, a QF is assumed to partially displace the next deferrable resource in the Company's latest IRP which occurs in 2027 in the 2013 IRP Update. Consequently, avoided capacity costs of a proxy resource are only included in the avoided cost calculation once that proxy resource is included in the Company's resource procurement plan. It does not make sense to include additional capacity payments during the sufficiency period for a small QF when it is not appropriate for a larger QF.

**Q. Given the Company's resource procurement plans, are retail customers indifferent under the current method of including capacity costs in the sufficiency period?**

A. No. In order to maintain the ratepayer indifference objective, deferred capacity costs must be included in avoided costs in a manner consistent with the Company's resource procurement plans identified in the IRP or IRP update. The Company's latest plan, the 2013 IRP Update, indicates that the next avoidable thermal resource will not be procured until 2027, and that the Company will rely on wholesale market transactions to meet its resource needs prior to that time. Schedule 37 avoided costs should not include the capacity costs of a SCCT when the Company cannot avoid such costs.

**Volumetric Rates**

**Q. Please explain the Company's proposal related to the payment structure available to QFs under Schedule 37.**

A. The Company proposes to replace the separate capacity and energy pricing with volumetric winter and summer prices for on-peak and off-peak hours. The separate capacity and energy payment structure results in over-payments to low-capacity-factor resources such as wind and solar QFs. Structuring Schedule 37 prices as volumetric rates ensures customers remain indifferent regardless of the type of QF resource.

**Q. How are the separate capacity and energy prices calculated under the current Schedule 37 tariff?**

A. Under the current Schedule 37, a QF is paid separate capacity and energy payments. The capacity payment, stated as a fixed dollars-per-KW-month amount, is calculated based on the fixed costs of the deferrable proxy resource and paid based on the QF's maximum generation during peak hours regardless of whether that maximum generation coincides with the Company's system peak hour. The current energy price is differentiated by season (winter and summer) and is determined based on the avoided energy costs as modeled by the GRID model during the sufficiency period and the fuel and capitalized energy costs of the proxy CCCT during the deficiency period.

**Q. Does the separate capacity and energy pricing over-compensate intermittent QFs with a low capacity factor?**

A. Yes. Under the capacity and energy payment structure, the QF is paid the same total dollars for capacity regardless of its generation output. However, the nature of an intermittent resource is such that it is unpredictable whether it will actually generate during peak hours. Furthermore, a CCCT provides several benefits to the utility that are not provided by an intermittent QF, including the ability to dispatch the resource on an as-needed basis and the ability to provide reserves. Under a volumetric pricing option, the QF will receive the total capacity dollars only if it generates an equivalent amount of energy as the avoided resource during on-peak hours.

**Q. How are the proposed volumetric prices calculated for Schedule 37?**

A. The proposed Schedule 37 rates include volumetric prices differentiated by season (summer and winter) and by on- and off-peak hours. During the sufficiency period, the avoided energy costs calculated in GRID are differentiated by season and then shaped to on-and off-peak periods consistent with the shape of wholesale market prices at the Palo Verde market hub. During the deficiency period, off-peak prices are equal to the energy cost of proxy CCCT, while on-peak prices include the energy cost of the proxy CCCT plus the avoided capacity costs spread to the on-peak hours using the capacity factor of the proxy resource as defined in the IRP. Tables 6A through 6D in Exhibit 3 of the Company's filing show the calculations for a base load resource, wind, fixed solar and tracking solar, respectively.

**Q. Does this conclude your direct testimony?**

A. Yes.